STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 13-12-010:

This is the proposed decision of Administrative Law Judge (ALJ) David M. Gamson. It will appear on the Commission's June 11, 2015 agenda. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Pursuant to Rule 14.3, comments on the proposed decision must be filed within 20 days of its mailing and reply comments must be filed within 5 days after the last day for filing comments.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Gamson at dmg@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:ar9

Attachment

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 5/5/2015)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 13-12-010 (Filed December 19, 2013)

DECISION ON COMBINED HEAT AND POWER PROCUREMENT MATTERS

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DECISION ON COMBINED HEAT AND POWER PROCUREMENT MATTERS

Summary

Today's decision establishes procurement targets for the Combined Heat and Power (CHP) Program's Second Program Period. We revise our greenhouse gas Emissions Reduction Targets to collectively achieve 2.72 Million Metric Tonnes of emissions reductions from CHP facilities by 2020. The Transition Period will end on July 1, 2015. We also establish a schedule of four competitive solicitations for CHP facilities between now and 2020. We make certain clarifications to the CHP greenhouse gas emissions accounting methodology. Last, we make various administrative clarifications in the CHP program's Second Program Period.

This proceeding remains open.

1. Background

In Decision (D.) 10-12-035, the Commission adopted the "Qualifying Facility and Combined Heat and Power Settlement Agreement" (QF/CHP Settlement). Combined Heat and Power (CHP), also commonly referred to as cogeneration, produces electricity and useful thermal energy in an integrated system. When properly designed, production of these two products can be more fuel efficient than separate conventional electric generation and heat production. As a result, fewer greenhouse gas (GHG) emissions can result from a CHP facility, depending on the comparisons made. In 2008, the Commission recommended to the California Air Resources Board (CARB) in D.08-10-037 that CHP be considered an emissions reduction strategy for the electricity sector. The CARB, in its 2008 Scoping Plan, listed CHP as a key strategy for reducing GHG emissions reductions: "The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants."[1]

While there are many different technologies that can perform as a CHP facility, for the purpose of today's decision there are two different broad categories of CHP – topping-cycle CHP and bottoming-cycle CHP. In a topping-cycle CHP facility[2], the facility produces electricity first and then captures the waste heat from that generation and uses it in a thermal application. In a bottoming-cycle CHP facility, the heat is produced first and applied to an industrial process, and then lower-grade waste heat is captured and used to generate electricity. Most relevant for today's decision, as established in D.09-06-051, we limit the attribution of GHG emissions associated with the electricity from a bottoming-cycle facility to just the supplemental firing[3] used since no new fuel is used during the production process.

While the QF/CHP Settlement resolved multiple long-standing contentious issues, D.10-12-035 primarily established a CHP procurement program. As stated in D.10-12-035, "this new program is designed to preserve resource diversity, fuel efficiency, GHG emissions reductions and other benefits and contributions of CHP." D.10-12-035 continues that the new program is designed "to promote new, lower GHG-emitting CHP facilities and encourage

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[1] *See* 2008 CARB Scoping Plan, at 42-43.

[2] We provide these generic definitions as a courtesy – Pub. Util. Code § 218(b) provides the formal definition of cogeneration, including exemptions appropriate for the application of useful thermal heat.

[3] Since bottoming-cycle CHP uses "waste heat" as its primary input to generate electricity, a bottoming-cycle CHP facility operator will often combust a small amount of natural gas to stabilize the heat to a consistent level suitable for electricity production. This process is known as supplemental firing.

the repowering, operations changes through utility pre-scheduling, or retirement of existing, high GHG-emitting CHP facilities."

This CHP procurement program features both an Initial Program Period (from the QF/CHP Settlement Effective Date of November 23, 2011[4] until November 23, 2015) and a Second Program Period (from November 24, 2015 until December 31, 2020). The QF/CHP Settlement also created a Transition Period, which lasts from November 23, 2011 until July 1, 2015. This Transition Period enables a cohort of existing CHP facilities to either obtain a new power purchase agreement (PPA), elect to sell into wholesale market, shut down, or cease export to the grid. Today's decision primarily focuses on implementation details of the Second Program Period, deferred in the QF/CHP Settlement to the Long-Term Procurement Plan (LTPP) proceeding. Today's decision also resolves issues surrounding uncertainty created by a delay in commencement of the QF/CHP Settlement implementation,[5] which primarily impacts the Transition Period.

In D.10-12-035, the Commission established two over-arching goals for the QF/CHP Program. The first goal was to transition CHP procurement from a federal-jurisdiction[6] standard-offer pricing model to a procurement program under state-jurisdiction using a market-based approach for pricing.[7] The second

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[4] As established in D.11-10-016.

[5] As discussed in D.11-10-016.

[6] As authorized by Congress in Public Utilities Regulatory Policy Act (PURPA) of 1978. *See* U.S.C. § 796, *et seq.* Under PURPA, a QF would be eligible for a standard-offer must-take contract priced at an avoided cost.

[7] QFs are paid a short run avoided cost (SRAC). The capacity price for SRAC was determined in D.07-09-040 and the energy prices are established in D.10-12-035, with a transition to a market basis in 2015.

goal was to optimize the state's existing CHP fleet as a GHG emissions reduction strategy. We re-affirm these two guiding principles in considering the matters before us today.

In addition to these two primary objectives, D.10-12-035 enumerated multiple additional policy objectives for procuring CHP. CHP is considered to be a preferred resource in the state's "loading order"[8] and in statute. Public Utilities Code Section (Pub. Util. Code §) 372(a) states "it is the policy of the state to encourage and support the development of [CHP] as an efficient, environmentally beneficial, competitive energy resources that will enhance the reliability of local generation supply, and promote local business growth." D.10-12-035 cites to this statute and also calls out "the purpose of the State CHP program is to encourage the continued operation of the state's existing CHP facilities, and the development, installation and interconnection of new, clean and efficient CHP facilities, in order to increase the diversity, reliability and environmental benefits of the energy resources available to the State's electricity consumers."[9]

Within the Initial Program Period of the CHP Program, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) all collectively agreed to procure CHP on a competitive basis through a series of three CHP-only Request For

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[8] In 2003, the Commission, the California Energy Commission, and the California Power Authority adopted an Energy Action Plan, articulating a single, unified approach to meeting California's electricity and natural gas needs. A key element was the "loading order" which specified California's policy to invest first in energy efficiency and demand response, then renewables and distributed generation before convention generation. CHP, as a form of distributed generation, is given preferred resource status in the loading order.

[9] *See* QF/CHP Settlement Term Sheet, Term 1.2.1.3, at 5.

Offers (RFOs). The combined total of procurement in the Initial Program Period was 3,000 Megawatts (MW).[10] D.10-12-035 also established a series of specific procurement rules including GHG Emissions Reductions Targets from CHP resources and accounting methodologies of GHG emissions reductions specific to CHP procurement, amongst others.

In Rulemaking (R.) 08-06-024, D.09-12-042 adopted two standard offer contracts for small, highly efficient and new CHP facilities,[11] as authorized by Assembly Bill (AB) 1613.[12] This program is known as the AB 1613 Feed-in-Tariff. The California Energy Commission (CEC) created a minimum efficiency rule for eligible CHP technologies of at least 62%. In 2011, the Commission modified the Self Generation Incentive Program (SGIP) to expand eligibility to technologies that reduce GHG emissions, including some CHP technologies. The SGIP uses the AB 1613 Feed-in-Tariff requirements.[13]

Last, in 2010 Governor Jerry Brown created a Clean Energy Jobs Plan[14] which outlines his vision for a variety of clean energy strategies. Specific to CHP, the plan calls for an additional 6,500 MW over the next 20 years.

2. Procedural Issues

The May 6, 2014 Scoping Memo in this proceeding specified that CHP matters may be addressed separately from the other Phase 1A issues. In that

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10 D.10-12-035 allows SDG&E to defer 51 MW of this 3,000 MW Capacity Target until the Second Program Period.

11 D.11-04-033 provides an extensive procedural history of the AB 1613 Feed-in-Tariff program and we do not repeat it here today.

12 AB 1613 was subsequently modified by AB 2791. See Pub. Util. Code § 2840.

13 *See* D.11-09-015, at 14.

14 Available online at http://gov.ca.gov/docs/Clean_Energy_Plan.pdf at 6.

vein, today's decision is limited to CHP matters, and we do not address any additional parts of the proceeding here.

On July 29, 2014, the assigned Administrative Law Judge issued a ruling seeking comment on CHP issues under consideration for this docket. The ruling contained the following seven questions, all designed to ascertain parties' positions on procurement details deferred to the Second Program Period of the CHP Procurement Program :

1. Should the Commission change or leave constant the utilities' GHG emissions reduction obligation for the Second Program Period?
2. What procurement processes and strategies should the Commission direct the utilities to achieve the goals and targets of the Second Program Period?
3. How many competitive RFOs should the Commission require the utilities to hold in the Second Program Period?
4. Should the Commission change the methodology or the assumptions on how to calculate GHG emissions reductions from CHP?
5. Should the Commission modify the procedural method for monitoring progress of the CHP program during the Second Program Period?
6. Should the Transition Period be extended to coincide with the end of the First Program Period?
7. Should the Commission establish special targets or rules to promote CHP resources that have significant potential to reduce GHG emissions, such as bottoming-cycle CHP or renewably fueled CHP?

Opening Comments were jointly filed by PG&E, SCE and SDG&E; other parties filing Opening Comments were Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC/CAC), the California Cogeneration Council (CCC), the Sierra Club and California Environmental

Justice Alliance (Sierra Club/CEJA), Alliance for Energy Retail Markets (AReM), the Commission's Office of Ratepayer Advocates (ORA), California Clean Distributed Generation Coalition (CCDC) and Marin Clean Energy (MCE). Reply Comments were filed separately by PG&E, SCE, SDG&E, EPUC/CAC, The Utility Reform Network (TURN), Natural Resources Defense Council (NRDC), Sierra Club/CEJA, CCC and ORA.

3. Establishing 2020 CHP Emission Reduction Targets

In D.10-12-035, the Commission established two procurement targets for the CHP Program. The first target, the focus of the Initial Program Period, is a 3,000 MW Capacity Target that must be met by 2015. The second target is a GHG Emissions Reduction Target that must be met by 2020, which is derived from the 2008 CARB Scoping Plan. The Scoping Plan establishes a statewide target of 6.7 Million Metric Tonnes (MMT) of GHG emissions reductions from CHP. D.10-12-035 adjusts this target for retail sales of the investor-owned (IOU) utilities (PG&E, SCE and SDG&E), which translates into a proportionate allocation of approximately 4.8 MMT. With the adoption of D.10-12-035, the Commission recognized that this Second Program Period target could be adjusted in the LTPP proceeding. D.10-12-035 defers implementation details concerning the targets for the Second Program Period to this proceeding, including whether or not to adjust the overall 2020 GHG Emissions Reduction Target or to translate that Target into a specific MW procurement mandate.

D.10-12-035 recognizes that the MW Capacity and GHG Emissions Reduction Targets interact with each other; any GHG emissions reductions achieved from the procurement of the 3,000 MW during the Initial Program Period also apply to the overall GHG Emissions Reduction Target. For example, if during the Initial Program Period the three utilities procured highly-efficient

CHP facilities to satisfy the Capacity Target, then the GHG Emissions Reduction Target could be largely satisfied. Conversely, if the utilities capacity procurement choices during the Initial Program Period were relatively inefficient CHP, then the GHG Emissions Reduction Target would be largely unmet. Thus, in order to provide context for the Second Program Period, we should consider the three utilities' progress to date on reducing GHG emissions from CHP. Our consideration will focus primarily on whether we should make an adjustment to the GHG Emissions Reduction Target. We use this decision to validate if the premise behind the dual procurement targets made in D.10-12-035 holds true. As discussed below, given the relative difficulties in optimizing the CHP fleet for GHG emissions reductions, we elect to make a modest reduction to the GHG Emissions Reduction Target for the Second Program Period.

Parties' recommendations regarding the GHG Emissions Reduction Target for the Second Program Period vary widely, ranging from reductions to increases, as well as no change. In Opening Comments, PG&E, SCE and SDG&E jointly argue that the 4.8 MMT target should be reduced. While they do not propose a new target, the three utilities argue that a lower target is more feasible and cost–effective. In particular, they argue that CHP as a GHG emissions reduction strategy may only be effective in the near term. "Investing in CHP resources at this time commits capital to a technology that relies primarily on natural gas as a source for meeting process steam and process heat requirements. While this *may* be beneficial for reducing natural gas and thus GHG emissions in the period of 2020-2030, in the longer term such requirements may need to be met with renewable fuels or electricity in order to achieve California's aggressive

GHG reductions goals. Without a longer-term focus, California's electricity customers may pay too much for too little GHG emissions reduction."[15] The three utilities collectively argue that the Commission should establish a working group to ascertain a new GHG Emissions Reduction Target. PG&E and SDG&E argue that additional procurement beyond system need "may contribute to the risk of over generation."[16] Thus the utilities argue that it is critical that there be a finding of need in addition to GHG emissions reductions. "If a need for new resources is identified in the LTPP, the full operational and environmental implications and associated costs of different technology options should be taken into account, and it should not be assumed that procurement to achieve GHG emissions reductions would necessarily fulfill that need."[17] SDG&E argues in its Reply Comments[18] that "reduced economic growth of the California economy, and energy efficiency and demand response have reduced the need for new generation" and renewable distributed generation technologies that provide GHG reductions are now more cost-effective.

EPUC/CAC also argues that Commission needs to have a longer-term vision for CHP beyond the Second Program Period's end date of December 31, 2020.[19] For the 2020 time frame, EPUC/CAC suggests maintaining the 4.8 MMT target and translating that targeting into a Capacity Target. Last, EPUC/CAC argues that already-achieved GHG emissions reductions from CHP, estimated at

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15 Opening Comments of PG&E, SCE and SDG&E, at 10.

16 *Ibid.*, at 11.

17 *Ibid.*, at 12.

18 Reply Comments of SDG&E, at 13.

19 Opening Comments of EPUC/CAC, at 5.

1.95 MMT, should be a consideration in adjusting the overall target. CCC concurs: "[T]he 4.8 [MMT] GHG reduction target was incremental to the existing reductions in GHG emissions from existing CHP. To the extent that existing efficient CHP is not retained, the state loses the benefits from which CHP is contributing to GHG reductions."[20] CCC continues to argue that the "IOUs should be incentivized to secure the GHG savings from efficient CHP, and not just from CHP that shuts down or that changes operations to become non-CHP [Utility Pre-Scheduled Facilities]."[21] CCC also points to the Governor's 6,500 MW goal to reason that there should an additional MW set-aside during the Second Program Period.

ORA provides analysis indicating that the GHG emissions reduction from CHP are relatively more expensive when compared to other potential electric resources. "ORA's analysis of [PG&E's, SCE's and SDG&E's] data found the average [Net Market Value] of a GHG emissions reduction credit to be $-26.05 and the median [Net Market Value] to be $-44.07 for the contracts executed since December 1, 2013."[22] ORA suggests that the underlying assumptions that led to the CARB Scoping Plan 6.7 MMT (and by extension, the Commission's D.10-12-035 adoption of the 4.8 MMT) are no longer valid. ORA points to a CEC consultant study, which suggests that "new CHP would result in between 1.4 and 4.5 MMT GHG emissions savings."[23] This was a 2012 study prepared by ICF International, Inc. for the CEC, entitled Combined Heat and Power: *Policy*

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[20] Opening Comments of CCC, at 4.

[21] *Ibid.*, at 7.

[22] Opening Comments of ORA, at 8.

[23] *Ibid.*

Analysis and 2011 – 2030 Market Assessment (2012 CEC Report).[24] ORA contends that the CEC study states that the potential for new CHP is mostly in smaller systems, which provides fewer GHG emissions reductions when compared to larger facilities.[25] ORA thus contends that the 4.8 MMT target is too high and not cost-effective when compared to other GHG emissions reduction strategies.

TURN supports ORA in its assessment overall. TURN advocates[26] a ratepayer "safeguard to avoid forcing utilities to procure 'CHP Machines,' that is, CHP facilities that – somewhat like the original 'PURPA machines' – are created solely to take advantage of regulatory procurement mandate, and not as a means for reducing carbon emissions from facilities that would otherwise not use their waste heat." TURN indicates that a "market test"[27] is the best way to determine cost-effective viability of CHP potential but takes no position on what the overall target should be for that market test.

AReM indicates that it takes "no position" on whether or not the Commission should change the GHG Emissions Reduction Target, but does indicate a willingness to let non-bundled Electric Service Providers (ESPs) do the procurement on their own behalf. AReM indicates that a successful track record in the Resource Adequacy, Renewable Portfolio Standard (RPS) and Energy Storage markets could translate into successful CHP procurement.[28]

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[24] Report No. CEC–200-2012-002-Rev. June 2012. This report is available on the CEC's website.

[25] *Ibid.*, in reference to CEC, Combined Heat and Power: Policy analysis and 2011-2030 Market Assessment, prepared by ICF International, Inc.

[26] Reply Comments of TURN, at 4.

[27] *Ibid.*, at 7.

[28] Opening Comments of AReM, at 3-4.

From an environmental perspective, Sierra Club and CEJA argue that the Commission should maintain the 4.8 MMT Target.[29] Sierra Club and CEJA contend that CHP "represents 15 percent of the Scoping Plan's principal GHG measures for the electricity sector." They continue that maintaining the GHG Emissions Reduction Target "offsets the risk that other sector targets may not be met."[30] In Reply Comments, Sierra Club and CEJA contend that if the current goal is not yet being met, then "the solution should not be to abandon the goal, but to fix the current program and create a more attractive market environment for new, efficient and renewable CHP."[31]

CCC argues in response to PG&E, SCE and SDG&E that the proper forum for arguing the Scoping Plan target is at the CARB and not in this proceeding. We disagree. D.10-12-035 is clear[32] that the LTPP proceeding provides the proper context for evaluating GHG emissions reductions from CHP and how to balance that target with both system and local need. In Reply Comments, EPUC/CAC points to D.10-12-035, which states that the GHG Emissions Reduction Target is just one expression of the overall goals and objectives of the CHP Program. EPUC/CAC contends that simply looking at GHG emissions reductions on a cost-per-unit reduction basis does not capture the other benefits of CHP endorsed by D.10-12-035, such as resource diversity and reliability. We agree with EPUC/CAC on this point; D.10-12-035 established the overall framework of determining the appropriate amount of CHP procurement as an

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[29] *Ibid.*, at 3.

[30] *Ibid.*, at 4.

[31] Reply Comments of Sierra Club and CEJA, at 2.

[32] *See* D.10-12-035 at 18.

expression of GHG emissions reductions, but our determination today can use additional factors to help us determine the appropriate magnitude of that target.

The capacity procurement activity from the Initial Program Period's 3,000 MW Capacity Target did make partial progress towards the 4.8 MMT GHG Emissions Reduction Target. As mentioned by multiple parties in comments, the to-date progress is important for determining if the GHG Emissions Reduction Target for the Second Program Period should be changed. D.10-12-035 ordered the creation of a CHP Semi-Annual Report to help facilitate this type of information exchange. No party contests the veracity of the report, and we use[33] its contents to help determine the relative adjustments we order today. The July 2014 CHP Semi-Annual Report indicates the reductions achieved to date, as follows:

Table 1: Utility Progress to GHG Emission Reduction Targets

(Million Metric Tonnes, MMT)	**PG&E**	**SCE**	**SDG&E**	**Total**
GHG Emissions Reduction Target Established in D.10-12-035	2.17	2.15	0.50	4.82
Utility Progress Towards Goal as of 7/7/14	1.34	0.74	0.01	2.09
Remaining GHG Credits Needed (without any adjustment)	0.83	1.41	0.49	2.73

As of the July 2014 Semi-Annual Report, the three utilities are approximately 43% of the way to reaching the GHG Emissions Reduction Target established in D.10-12-035.

[33] Per Rule 13.9 of the Commission's Rules of Practice and Procedure, we take official notice of the CHP Semi-Annual Report Dated July 7, 2014. This publically available report is available online at http://www.cpuc.ca.gov/PUC/energy/CHP/settlement.htm.

As we consider what the appropriate target is for the Second Program Period, we are posed with parties' varied recommendations to reduce or increase the GHG Emissions Reduction Target, or per Settlement Term Sheet Section 6.7.1, adopt in this decision an adjusted GHG Emissions Reduction Target pursuant to an official CARB document that modifies the CHP Recommended Reduction Measure. The 2013 updated CARB Scoping Plan is ambiguous whether CHP is included among the measures necessary to reduce emissions pursuant to AB 32. It states that "[a] future CHP measure could establish requirements for new or upgraded CHP systems" while also stating that "[the State's energy agencies will] achieve the Governor's objectives and that of the Initial Scoping Plan for CHP to reduce GHG emissions."[34] However, in the itemization of the "foreseeable measures" necessary to determine the amount of GHG reductions needed to reduce to 1990 emissions, CHP is excluded.[35] This ambiguity will not bind the Commission's determination of a GHG Emissions Reduction Target for the Second Program Period. We consider deviations from the current GHG Emissions Reduction Target of 4.8 MMT only with significant good cause.

The record shows that there is good cause to adopt a lower GHG Emissions Reduction Target for the Second Program Period. ORA contends that it is possible for more cost-effective GHG emissions reductions to come from

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[34] CARB 2013 Scoping Plan, at 42 and 45.

[35] The 2013 Scoping Plan at 93 references "GHG Reductions from Ongoing, Adopted, and Foreseeable Scoping Plan Measures" listed at http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf that corresponds to Table 5. The "Increase CHP use" Measure No. E-2 from the 2008 Scoping Plan at 44 is excluded from the Electricity and Natural Gas Measures.

other resources. While we do not speculate today on the relative cost of GHG emissions reductions compared to other procurement options, we agree with the IOUs and ORA that there are significant concerns about the cost-effectiveness of future CHP procurement. We also agree that other preferred resource technologies are reasonably likely to provide greater emissions reduction potential in future years. Further, recent changes in the electric grid such as the potential for reliability problems resulting from over-generation point in the direction of a lower mandate for CHP in the future, as CHP resources have a significant potential to contribute to the over-generation concern. Therefore, we find that a downward adjustment is appropriate for the Second Program Period.

While we will reduce the GHG Emissions Reduction Target, we are persuaded by EPUC/CAC and others that the Second Program Period GHG Emissions Reduction Target needs to be robust enough to achieve the CHP policy objectives established in D.10-12-035 beyond GHG emissions reductions. We also recognize the concern of Sierra Club and CEJA that continued investment in efficient GHG-reducing CHP may serve as a risk hedge against possible shortfalls in other GHG emissions reductions strategies. Thus, we do not intend to lower the GHG Emissions Reduction Target as low as some parties advocate. The modified targets for the Second Program Period we establish in this decision seek to balance the basis for measuring progress (emissions) against considerations of cost and need.

The utilities request that the Commission convene a working group to revise the basis to establish a new GHG Emissions Reduction Target. However, we share CCC's concern that, given the parties' divergent positions on fundamental issues like the need and cost for procurement and technical issues that would affect the attainment of the target like the Double Benchmark and potential thermal demand, such working group would require lengthy negotiations and be very resource intensive.[36] The time required for this working group would prove disruptive to the CHP facilities that require regulatory and market certainty, a primary objective of the CHP Program.[37]

In lieu of a working group, we will establish a GHG Emissions Reduction Target for the Second Program Period at this time to provide certainty going forward. As discussed herein, the target should be lower than the current levels because of the policy imperative to balance the stimulation of CHP procurement and the cost-effective achievement of long term emissions reductions, ensuring that the Program provides reasonable value to ratepayers and aligns with the state's need for new electric generating capacity. None of the parties' positions provide reasonable calculations for the new target. We instead utilize the June 2012 CEC Report as a basis to establish the magnitude of the GHG Emissions Reduction Target for the Second Program Period. This study provides the most useful and specific information in the record for calculating future GHG emissions reductions, and is consistent with our policy objectives.[38]

The June 2012 CEC Report provides Base, Medium, and High Cases for emissions reductions from CHP for each of the utilities' service territories.[39] The Report's Base Case assumes the existence of the following policies and programs:

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[36] Reply Comments of CCC, at 2.

[37] QF/CHP Settlement Term Sheet Section 1.2.2.1, at 6.

[38] We note that in addition to CPUC, CEC, and CARB staff, representatives for CCC and CAC/EPUC provided information and commented upon the June 2012 CEC Report.

[39] CEC, Combined Heat and Power: Policy analysis and 2011-2030 Market Assessment, at 102-116.

Cap and Trade, SGIP authorized until January 2016, 33% RPS, AB 1613 export pricing for CHP <20MW, and SRAC export pricing for CHP greater than or equal to 20 MW. Currently, CHPs less than or equal to 20 MW are eligible for two programs with different energy pricing terms: the AB 1613 Feed-In-Tariff differentiated by power rating and the standard offer contract approved in the QF/CHP Settlement with SRAC pricing. CHPs larger than 20 MW are subject to competitive procurement and may (but do not automatically) receive compensation for exports at SRAC.

The Report's Medium Case builds upon the Base Case. The Medium Case assumes that SGIP is legislatively extended with gradual incentive level reductions. This assumption is aligned with D.14-12-033, which authorized the IOUs to collect funds for SGIP until 2019 and contemplated future program design modifications per Senate Bill 861 (2014). The Medium Case relies on additional stimuli for exporting projects by assuming that CHPs are compensated for exports at the 2011 Market Price Referent (MPR), that the investors accept paybacks less than six years, and that removing barriers and risk would increase market participation by 5-20%. Currently, the MPR is not utilized for compensating CHP electricity exports. Further, it is unclear whether the additional investment and market dynamics that the Study assumes will be realized.

The Report's High Case builds upon the Medium Case. Additional policies included in this scenario include the elimination of non-bypassable charges, utility ownership of large CHPs that have a greater focus on electricity production, and a state investment tax credit for CHP of any size without an end date. The High Case also assumes that competitive CHP markets will decrease capital cost for new CHP by 10% by 2030, and that removing barriers and risk would increase market participation by an additional 2-7%.

We will not use the High Case because the level of CHP deployment is driven by several policies that have not been adopted and that are not within the scope of this proceeding. As discussed later herein, the elimination of non-bypassable Charges will not be addressed in this proceeding. Per Settlement Term Sheet Section 4.7.1, the utilities are restricted to owning capacity equivalent to 10% of their share of the GHG Emissions Reduction Target. We will not amend that negotiated limit here, nor do we find it reasonable to influence the design of CHP operations beyond the Federal Energy Regulatory Commission's (FERC) requirement that new CHPs use at least 50% of their annual energy output for useful purposes to demonstrate that they are not intended fundamentally for the sale of electricity.[40] Currently there is no investment tax credit specific to CHP. We are also concerned that using the High Case would disrupt the achievement of the policy balance we strive for in this decision because the needs assessments in recent LTPP decisions have not identified a need for the utilities to procure new generic system generating capacity.[41] To add thousands of MW of new, likely natural gas-fired, CHP generating capacity when no need has been identified could have potentially deleterious effects on the grid, impose cumulative investment costs on ratepayers on the order of

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[40] FERC Order No. 671, at 49.

[41] In D.13-02-015 for SCE and D.14-03-004 for SDG&E, the Commission determined procurement requirements for Local Capacity Areas. None have been identified for PG&E.

$5 billion,[42] and could "crowd out" renewable resources that may be needed to reach the governor's goal of 50% renewable energy by 2030.

Likewise, we will not adopt the Base Case scenario, as this scenario is likely too low to promote new CHP development once the utilities' current progress toward the target is taken into account. As discussed earlier in this decision, the Commission will count the GHG Credits that the utilities have procured to date toward the new GHG Emissions Reduction Target for the Second Program Period ending in 2020. To set a new target at this point in the program that "wipes the slate clean" of the progress the utilities have made thus far would penalize those utilities that took early aggressive action to meet the GHG Emissions Reduction Target and reward those that have performed poorly. Since we are counting the GHG Credits the utilities have thus far, it is reasonable to choose a scenario that is more ambitious than the Base Case in order to accommodate additional CHP procurement.

Therefore, we will use the June 2012 CEC Report's Medium Case to establish the Second Program Period GHG Emissions Reduction Target. The Medium Case assumes existent underlying policy, and the additional CHP capacity resulting from policies not currently enacted are consistent with the need to balance policies toward stimulating additional CHP procurement, ensuring adequate cost control, and providing opportunities for other beneficial resources. The Medium Case estimates that the total annual CO_2e emissions reduction potential for the utility service territories by 2020 is 2.72 MMT.[43] With all of these factors under consideration, we apportion the 2.72 MMT according to

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[42] June 2012 CEC Report at Appendix D, Tables D-9, D-10, and D-11.

the utilities' most recently-available retail sales figures from 2013[44] and we set the GHG Emissions Reduction Target for the Second Program Period as follows:

Table 2: Revised GHG Emissions Reduction Targets and Remaining Need

(Million Metric Tonnes, MMT)	**PG&E**	**SCE**	**SDG&E**	**Total**
Revised Second Program Period GHG Emissions Reduction Target	1.22	1.22	0.28	2.72
Utility Progress Towards Goal as of 7/7/14	1.34	0.74	0.01	2.09
Remaining GHG Credits Needed (adjusted)	0*	0.48	0.27	0.75*

* PG&E progress to the revised target would result in a negative value of 0.12 MMT, so PG&E's target will be zero. The total for SCE and SDG&E exclusive this negative PG&E value is 0.75 MMT.

We view the new GHG Emissions Reduction Target that we mandate today as a critical market signal for the next phase of CHP development in California. The need authorization should both benefit ratepayers and be reasonable for infrastructural investments made by third-party CHP developers. Ideally, CHP would be situated at locations where inefficient boilers are displaced by a system that can generate both industrial-grade heat and electricity. We note that CHP, as a form of distributed generation, both displaces electric load and delivers baseload generation onto the grid. Thus, if we drastically alter the GHG Emissions Reduction Target associated with CHP

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[43] June 2012 CEC Report at Appendix D, Tables D-9, D-10, and D-11.

[44] Pro-rata apportionment of the GHG Emissions Reduction Target is required per Term Sheet Section 6.2.2.3.2, which the Energy Division updates according to annual changes in retail sales using the GHG ERT Calculator at: http://www.cpuc.ca.gov/PUC/energy/CHP/settlement.htm.

procurement, we may unintentionally cause efficient existing CHP facilities without future contract certainty to shut down, and undermine the state's efficiency and distributed generation goals.

As discussed above, we envision that many of the GHG benefits will come from the fleet of existing CHP. Optimization of existing CHP facility operations can result in significant GHG emissions reductions. Therefore, we do not authorize procurements in terms of additional MW Capacity Targets at this time. Because PG&E has procured emissions reductions in excess of its service territory's potential identified in the CEC Study, PG&E will not be required to hold solicitations during the Second Program Period. The excess (0.12 MMT) shall not be applied to the remaining GHG Emissions Reduction Targets for the other two utilities. With the new target for CHP set, we now turn to procurement processes and strategies for the three utilities to employ during the Second Program Period.

4. CHP Procurement Processes and Strategies

In D.10-12-035, the QF/CHP Settlement, the Commission transferred CHP procurement into a new market-based regime via a series of competitive solicitations under an RFO process. In part, this change was made to allow CHP Facilities to optimize operations and to no longer need to fulfill the requirements of a standard offer contract. While CHP-only RFOs were the primary procurement strategy, a variety of different CHP procurement options were authorized in D.10-12-035, including an "Optional As-Available" program, bilateral negotiations, the PURPA-must take obligation for facilities under 20 MW, the AB 1613 Feed-in-Tariff for highly efficient new CHP, incentives for behind-the-meter facilities reducing GHG funded by the SGIP, and conversions to Utility Pre-Scheduled Facilities. In most cases, D.10-12-035 established that any method of CHP procurement or strategy counted towards the utilities' targets. We maintain this approach with additional clarifications for the Second Program Period.

PG&E, SCE and SDG&E seek clarification that the only MW Capacity Targets that should exist in the Second Program Period are SDG&E's 51 MW Capacity Target that was intentionally deferred, and any unmet MW resources from failed solicitations from Targets A, B or C of the Initial Program Period. Beyond that, the three utilities advocate for a continuation of the market-based approach established in D.10-12-035. ORA concurs with this sentiment, and indicates that no new MW Capacity Targets should be established given their view of the relatively high cost of CHP. Sierra Club and CEJA support[45] "the use of diverse procurement processes and strategies that can and should be used to meet the IOU GHG and MW targets. These should be adjusted to provide opportunity for building different sizes of CHP facilities and the deployment of different technologies." Sierra Club and CEJA state that without special attention there could be "significant adverse effects on air quality and public health." Sierra Club and CEJA advocate that "alternative procurement mechanisms may be required to induce retirement of existing CHP plants that use the dirtiest fuels (e.g., coal, petroleum coke, and diesel)… Specifically, new and upgraded facilities that use coal, petroleum coke and diesel should not count towards the CHP target."[46] Sierra Club and CEJA also advocate procurement processes and strategies that support "a diverse range of services from CHP," such as load following and balancing.

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[45] Opening Comments of Sierra Club and CEJA, at 5-6.

TURN indicates that it is sympathetic to Sierra Club and CEJA's objectives but "opposes establishing separate carve-outs based on technology and size."[47] With respect to existing resources, TURN indicates that unless existing facilities "need to make significant capital investments, such facilities should be able to compete in any RFO against new facilities."[48] TURN encourages additional workshops to resolve any barriers to existing CHP facilities.

EPUC/CAC contends that the procurement selections made by the three utilities during the Initial Program Period did not result in a viable market for baseload CHP. EPUC/CAC argues that the procurement to date is more of a "[Utility Pre-Scheduled Facility]/Dispatchable Product/RA program."[49] EPUC/CAC continues to say that CHP procurement under the program during the Initial Program Period has "not worked to incent combined heat and power over separate heat and power installations."[50] To remedy the situation, EPUC/CAC advocates separating procurement targets into two: existing resources and new resources: "Maintaining these existing resources is the first step in a successful program. This does not mean retaining CHP at any cost, but it does mean retaining such facilities at reasonable costs associated with their product and value." To accomplish this, EPUC/CAC advocates extending the

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46 *Ibid.*, at 7.

47 Reply Comments of TURN, at 7.

48 *Ibid.*, at 8.

49 Opening Comments of EPUC/CAC, at 8.

50 *Ibid.*, at 10.

seven-year term of the existing contracts.[51] EPUC/CAC does not propose any specific fix for perceived problems in the procurement of new CHP facilities.

CCC advocates that all of the existing procurement processes and strategies recognized in D.10-12-035 should continue to apply. CCC proposes a separate MW Capacity Target set-aside for the Second Program Period that may comprise only PPAs procuring power from efficient existing and new or repowered CHP facilities: "The results in the Initial Program Period…amply demonstrate that without the implementation of such a set-aside, CHP facilities, which were intended to be the focus on the CHP Program, may continue to be left without viable contracting opportunities within the CHP Program."[52]

CCDC provides extensive commentary on the AB 1613 Feed-in-Tariff procurement method. Amongst its positions, CCDC argues that the pricing mechanism and the treatment of GHG obligation costs are hindering uptake of this CHP procurement pathway. CCDC also cites high costs associated with interconnection (and other associated delays) as barriers to the AB 1613 Feed-in-Tariff.

We concur with PG&E, SCE and SDG&E that the AB 1613 Feed-in-Tariff issues raised by CCDC are outside of the scope of this LTPP proceeding. However, any future uptake or participation from CHP facilities of the AB 1613 Feed-in-Tariff should continue to be an active procurement strategy and count towards the utilities' targets. We also note that CCDC raised several other topics which might facilitate additional CHP procurement – such as reducing stand-by

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[51] *Ibid.*, at 11.

[52] Opening Comments of CCC, at 8.

charges and streamlining interconnection issues. We do not address these topics today since they are also outside of the scope.

We now turn to the other procurement strategies. D.10-12-035 established a broad "net" when it came to having CHP facilities count towards the overall program goals and targets. We re-affirm this overall strategy today since it aligns with our policy goal of transitioning CHP resources to a market-based procurement. We continue the primary method of competitive solicitations for large CHP resources and the other procurement options for the smaller facilities. No party suggests eliminating any of the existing procurement strategies and it is reasonable to maintain the existing multiple different procurement pathways.

Sierra Club and CEJA advocate for additional restrictions on the competitive solicitation process and other CHP procurement strategies to further an environmentally-oriented agenda of decreasing high-emitting, low-efficiency CHP. While we certainly laude the objective, we also decline to make a specific mandate at this time with respect to procurement strategies. The existing GHG emissions reduction accounting methodology established in D.10-12-035 (and as discussed in today's decision, below) and the exclusion of coal-fired QFs from counting toward the MW Capacity Target[53] is designed to achieve this result. Sierra Club and CEJA do not provide enough rationale as to why the existing

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[53] *See* QF/CHP Settlement Term Sheet, Term 5.2.4.2, at 29.

rules[54] are insufficient to result in more efficient natural gas-fired CHP or more non-natural gas-fueled CHP switch to a renewably-fueled process.[55]

We now turn to address the comments made specifically about facilities in the existing CHP fleet. EPUC/CAC and CCC both contend that additional consideration is needed for existing CHP facilities. We intend that most of the fleet optimization will be derived from contractual changes with the existing fleet, perhaps with some new CHP entrants replacing existing inefficient facilities that opt to shut-down. We affirm EPUC/CAC's identification that a key policy objective for the QF/CHP Settlement was to ensure the continued operation of the state's existing efficient CHP facilities. To this end, we envision that the existing efficient CHP fleet's aggregate generating capacity and associated extant emissions reductions will be preserved and that inefficient facilities will be replaced by new efficient CHP facilities. We do not elect to quantify this goal into a MW Capacity Target because the GHG Emissions Reduction Target established above acts as the market signal. As a result, we are not persuaded by CCC and EPUC/CAC to have a specific MW Capacity Target set-aside for existing facilities. We also decline to adopt EPUC/CAC's suggestion of further bifurcating the procurement strategies into new and existing CHP facilities.

We are persuaded, however, of the procurement problems facing existing CHP facilities as indicated by CCC and EPUC/CAC. While we decline CCC's

[54] QF/CHP Settlement Term Sheet Section 4.2.2.1 determines eligibility for Qualifying CHP facilities and requires compliance with the Emissions Performance Standard per Pub. Util. Code § 8341.

[55] QF/CHP Settlement Term Sheet Section 5.2.4.2 explicitly prohibited existing wood waste and renewable QFs from counting toward the utilities' MW Capacity Target because they would be eligible for procurement in the RPS programs. They were, and will continue to be eligible to count toward the GHG Emissions Reduction Target.

suggestion of a MW Capacity Target set-aside for existing, repowered, or new CHP (when compared to the other strategies), the results of procurement to date warrant an additional intervention for this cohort of existing CHP facilities.

The QF/CHP Settlement's construct for determining the IOUs' GHG Emissions Reduction Target and the GHG emission accounting methodology may have had the unintentional adverse consequence of discouraging the re-contracting of existing efficient CHP facilities, particularly those that do not change operations and therefore cannot provide GHG Credits. As discussed earlier, for the most part the IOUs have procured CHP within the QF/CHP Settlement constraints and re-contracted with cost-reasonable CHP capacity that provides flexibility suitable to their changing portfolios of resources and GHG emissions reductions. It is necessary though, for this decision to clarify sections within the Term Sheet to achieve our policy goals for existing CHP facilities. We describe how the Terms may have affected procurement decisions and establish a corrective change.

First, Section 4.2.12 permits the utilities to request offers that provide curtailment and dispatchability options that differ from the CHP RFO Pro Forma PPA adopted in D.10-12-035. The Section explains that the utilities will prefer Pro Forma offers, which are "the product contemplated by the program" if they are competitive according to 1) the standards of the program,[56] and 2) commensurate with the solicited product, over non-Pro Forma offers. The utilities are not precluded from selecting non-Pro Forma bidders but they cannot replace or substitute for the selection of "competitive" Pro Forma bids. As CCC

[56] For example the CHP RFO Scope, Evaluation, and Selection Criteria described in Section 4.2.5 of the QF/CHP Settlement Term Sheet.

notes,[57] it is possible and consistent with these terms that economic differences among facilities offering similar products (e.g., baseload without operational changes) caused the utilities to select the most valuable offer, but not others that may have deviated from the competitive level.

Second, Section 6.4.2 determines the IOU's GHG Emissions Reduction Targets by taking an inventory of the status of the existing CHP facilities upon the completion of the Initial Program Period. Sections 6.4.2.2 and 6.4.2.3 state that existing CHP facilities that "shut down within the Initial Program Period" will have the net of their GHG Debits added to, or GHG Credits subtracted from, the GHG Emissions Reduction Target. This Term measures the utilities' effectiveness of achieving the GHG goals by facilitating shutdowns of inefficient CHP and re-contracting with efficient CHP during the Program's transition to entirely market-based procurement. However, given imperfect information between a buyer and seller during the RFOs, the condition that the shutdown must occur *during the Initial Program Period* may have been an insufficient incentive to re-contract with efficient existing CHP facilities. There is uncertainty in assessing the viability of a thermal host served by a CHP facility that sells electricity in the market as compared to a "must-take" regime.

Third, Section 7.3.3.1 establishes that existing CHP facilities without operational changes are considered Neutral for GHG accounting purposes. Considering this Section in concert with the two above, the QF/CHP Settlement considers an existing CHP facility offering unchanged, efficient operations in two ways:

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[57] Opening Comments of CCC, at 10.

1) as Neutral, during the Initial Program Period, and
2) as its embedded GHG reductions, but only if after attempts at securing a contract during the Initial Program Period are unsuccessful and the facility is forced to shut down.

These Terms likely created a barrier to the utilities' pursuit of less-competitive existing CHP facilities offering Pro Forma operations because the CHP would not be debited against a utility's progress toward its GHG Emissions Reduction Target until after procurement activities are completed. The uncertainty from this procurement strategy may have resulted in a preference toward least cost MW and GHG Credits from dispatchable and flexible CHPs. Foremost, this construction of the QF/CHP Settlement contravenes the Program's objectives to provide business and regulatory certainty and support for the state's manufacturing, industrial, and commercial base.[58]

We agree with the suggestions of CCC and EPUC/CAC regarding the need to recognize the emissions reductions associated with the continued operations of the fleet of existing CHP facilities.[59] To avoid the negative outcomes above, the utilities are directed, with respect to prospective CHP procurement in the Second Program Period RFOs, to account for the GHG emissions from efficient existing CHP facilities with no change in operations as a GHG Credit calculated against the previous two calendar years of data compared to the double benchmark. This modification would, in effect, allow for the implementation of Section 7.3.2.2, which pertains to the calculation of a GHG

[58] QF/CHP Settlement Term Sheet Sections 1.2.3.3 and 1.2.4.6, at 6-7.

[59] Opening Comments of CCC, at 6 and 8; Opening Comments of EPUC/CAC, at 6-7.

Debit resulting from the shut-down or retirement of an existing, efficient CHP facility where their thermal need continues, without the CHP facility having to disrupt the operations of its thermal host.

The update to the GHG accounting methodology is a reflection of our policy preferences about existing efficient CHP facilities. We note that the utilities and ORA have argued that there are relatively high costs with these CHP contracts, and potential for them to contribute to over-generation conditions observed on the system. While we are sympathetic to ratepayer concerns, we anticipate that the benefits of avoiding the shutdown and loss of the embedded emissions reductions by enabling the continued operations of existing efficient CHP facilities will balance the additional procurement costs borne from the modification to the GHG accounting rules.

For all other procurement strategies, the contract terms established in D.10-12-035 and the Settlement Term Sheet remain unchanged.

5. Number of Competitive Solicitations During Second Program Period

We maintain our commitment to a competitive market for CHP resources, through a variety of procurement processes and strategies, with a competitive CHP-only RFO as the primary strategy. During the Initial Program Period, there were three competitive solicitations. For reasons we outline below, we extend this practice into the Second Program Period.

PG&E, SCE, SDG&E, Sierra Club and CEJA, EPUC/CAC and CCC all support maintaining competitive solicitations. TURN, NRDC, CCDC, ORA, MCE and AReM are neutral on this point. PG&E, SCE and SDG&E contend that the Commission should not yet mandate the frequency of competitive solicitations, since the three utilities advocate for additional analysis before the establishment of a Second Program Period target. Sierra Club and CEJA recommend more frequent solicitations, at least one or two solicitations per year, as a way of monitoring progress towards program objectives. EPUC/CAC advocates for additional analysis of the Second Program Period target to determine the total number of competitive solicitations, and ask to maintain the annual schedule of solicitations. CCC advocates for at least two competitive solicitations during the Second Program Period. CCC argues that at least one of those two should occur early in the Second Program Period to allow for any existing facilities with contracts expiring in the near-term to compete and transition as smoothly as possible.

All parties support maintaining competitive solicitations, or are neutral on the matter. Given our goal to transition CHP into a market-based resource, we elect to maintain the current structure of primarily procuring CHP through CHP-only RFOs. Since we established a Second Program Period GHG Emissions Reduction Target, we can go one step further and establish the number of solicitations to occur during the Second Program Period. We note that D.10-12-035 established that any capacity (measured in MW) that is not procured toward the MW Capacity Target during an individual RFO (Target "A," "B" or "C") in the Initial Program Period is transferred as a subsequent obligation (a Net MW Target) in the Second Program Period. The utilities are required to solicit any Net MW Targets remaining from the Initial Program Period in combination with the CHP GHG RFOs during the Second Program Period. SDG&E's MW Capacity Target of 51 MW (associated with the original 3,000 MW Capacity Target but deferred to the Second Program Period) shall be procured concurrently with the CHP GHG RFO but no later than 2018.

Sierra Club and CEJA, EPUC/CAC and CCC persuasively argue that the Commission receives valuable programmatic and market information from holding solicitations on a regular and predictable schedule. As we continue transitioning CHP into the market-based framework established in D.10-12-035, we agree with EPUC/CAC that regularity should be maintained. We are also persuaded by CCC that given the large cohort of existing facilities that have contracts that expire in the near term, the first solicitation should be held to ensure a smooth transition for facilities to the extent practicable.

Similar to the three sets of solicitations held during the Initial Program Period, we do not mandate specific dates and timeframes for the solicitations to occur except that the first CHP RFO must be initiated within 90 days of the start of the Second Program Period.[60] However, given the utilities' history and experience, we anticipate that these solicitations will likely continue on a near-annual basis. We therefore anticipate that the utilities may hold up to four CHP GHG RFOs designated with GHG Emissions Reduction Targets "D," "E," "F," and "G."[61] We do not allocate interim GHG Emissions Reduction Targets to each interim CHP RFO, for consistency with the structure of the GHG Emissions Reduction Target established in D.10-12-035. The GHG Emissions Reduction Target will remain a total amount to be attained by the end of the Second Program Period, December 31, 2020.

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[60] Analogous to Section 5.1.4.2 of the Settlement Term Sheet.

[61] The first three solicitations were labeled "A," "B" and "C." For the sake of continuity, the first RFO in the Second Program Period shall be labeled "D" and continue onwards.

Table 3: Second Program Period CHP RFOs

Utility	Remaining IOU GHG Emissions Reduction Target
SCE	0.48 MMT
SDG&E	0.27 MMT
Total Targets	0.75 MMT

As derived from Table 2, the column labeled "Remaining IOU GHG Emissions Reduction Target" is based on the July 2014 CHP Semi-Annual Report. If any of the GHG emissions reductions numbers change (e.g., because of a failed contract delivery) the increase in GHG emissions obligation should automatically flow to the next available solicitation (e.g., from GHG Target D to GHG Target E).[62] Similarly, if an earlier solicitation is more fruitful in reducing GHG emissions reductions, a utility can suspend the remaining solicitations upon attaining the target.

We now provide additional guidance on the structure of the subsequent CHP RFOs. On July 10, 2014, the Commission adopted a Safety Policy Statement and subsequently adopted a Safety Action Plan on February 12, 2015. The Statement and Action Plan require that safety be properly scoped in scoping memos and fully considered in proposed decisions.[63] In addition, Commission resolutions have considered how the contracting of CHP facilities affect the

[62] This process is analogous to the "Net MW Target" used for the Capacity Target during the Initial Program Period per Section 5.1.4.3 of the QF/CHP Settlement Term Sheet.

[63] Safety Policy Statement of the California Public Utilities Commission, at 2; Safety Action Plan and Regulatory Strategy, at 11.

utilities' obligations to maintain safe electric service for the public pursuant to Pub. Util. Code § 451. The utilities' procurement activities with CHP facilities thus far in the Initial Program Period have generally established contract terms and conditions that require the CHP facility to be operated in accordance with Prudent Electrical Practices. In directing additional utility solicitations for CHP resources, we suggest that the utilities complete a more holistic examination of safety risks associated with CHP procurement. During solicitations held pursuant to the attainment of the GHG Emissions Reduction Targets in the Second Program Period, the utilities are directed to assess all CHP offers for their effects on public and environmental health and safety. This safety assessment should include an evaluation of the CHP facilities in terms of existing applicable state or federal standards and programs in order to validate the likelihood of the counterparty operating the facilities in compliance with Prudent Electrical Practices.

6. Changes to GHG Emissions Reduction Accounting Methodology and Double Benchmark

In D.10-12-035, the Commission adopted a "double benchmark" approach for counting GHG emissions reductions from CHP facilities. The double benchmark is an accounting construct[64] to determine if the combined production of heat and electricity from a CHP facility is more or less efficient than producing the two products separately. Under the double benchmark methodology, if a

[64] We note that the CHP program's GHG emissions accounting rules are designed against a hypothetical comparison of separate generation of useful thermal heat and electricity. Therefore, the GHG emissions methodology is purely an accounting construct and not an accurate report of *actual* GHG emissions produced from the CHP facility.

CHP facility is more efficient than the benchmarks of an 80% efficient boiler (heat) and a heat rate[65] of 8,300 BTU/kWh (electricity), then the facility is reducing GHG emissions; if a facility is less efficient than these two benchmarks, then under the CHP Program's accounting construct the facility is increasing GHG emissions. The origins of the values for both the boiler efficiency and the electric grid's heat rate, while adopted in D.10-12-035, are from the 2008 CARB Scoping Plan; the GHG emissions reductions estimated in the CARB Scoping Plan for the electricity sector used this heat rate and assumed this boiler efficiency for CHP. We note that while D.10-12-035 adopted the double benchmark methodology, it also left room for the Commission to update the assumptions (the heat rate and the standard boiler) during the Second Program Period. For reasons we describe below, we elect to leave the double benchmark methodology unchanged.

Parties vary on changing the assumptions behind the double benchmark. PG&E, SCE and SDG&E collectively argue strongly for changing the assumptions. The three utilities argue that a more stringent set of benchmarks (a lower heat rate and higher boiler efficiency) is more appropriate; they contend that changing the double benchmark would be an accurate portrayal of the state's relatively clean electric grid and the recent advances in commercial boilers. The utilities continue with arguments that a more stringent double benchmark will show that GHG emissions from CHP are less cost-effective than from other electric emissions reduction strategies. We also note that attached to

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[65] A heat rate, measured in British Thermal Units per kilowatt hour (BTU/kWh), is a thermal electricity generation performance metric. The lower the number, the less natural gas the generator required to generate a kilowatt hour.

their opening comments is a paper written by PG&E about the double benchmark methodology and its underlying assumptions. We do not give that paper any evidentiary weight in making our decision today.

ORA also supports changing the assumptions behind the double benchmark methodology, especially in light of the 33% RPS becoming effective after the adoption of D.10-12-035. ORA argues that electric line losses are not accounted for in the double benchmark. NRDC continues along the same line, saying that the Commission "should only promote new CHP that meets or exceeds an updated efficiency standard for the heat and power it displaces."[66]

EPUC/CAC advocates not changing the double benchmark. EPUC/CAC discusses the system average heat rate for 2013's fossil generation and contends that the 8,300 heat rate is reasonable. EPUC/CAC also argues that the 80% boiler is higher than the comparable federal standard. CCC indicates that workshops are needed if any changes were to occur to either of the benchmark values.

In considering the various positions of the parties, we understand the motivations of the parties which advocate making the benchmark more efficient to better reflect the current conditions of the electric grid and advancements in boiler efficiency. Conceptually, over time as the achievement of state policies cause separate heat and grid power to become more efficient and/or de-carbonized, the marginal benefit of conventionally-fueled combined heat and power declines.

However, we ultimately disagree with the premise that a more stringent benchmark will result in fewer GHG emissions from CHP. As mentioned above,

[66] Reply Comments of NRDC, at 3.

the methodology adopted in D.10-12-035 is an accounting construct and does not accurately represent actual GHG emissions reductions attributable to any particular CHP facility. Rather, the 8,300 heat rate represents a "base case" against which all of the electricity emissions reduction strategies are measured against - a metric of how much progress has been made since the 2008 CARB Scoping Plan was adopted. As the electric grid has become cleaner, we mark the state's progress against this 8,300 heat rate as a matter of attribution. Since CARB did not update the embedded heat rate in its 2013 Scoping Plan Update, we are not persuaded that any update for this single emissions reduction strategy is appropriate. It is unreasonable for the benchmark for CHP's progress to be different than the other GHG emissions reduction measures. We note that it is possible that in the future either the Commission or CARB may elect to update the assumptions of this 'base case' to mark progress towards the 2020 GHG Emissions Reductions Targets. If that occurs, then we will consider modifications to the double benchmark in the broader context. For now, we leave the values for the double benchmark as 8,300 (electric grid heat rate) and 80% boiler (heat).

We now turn to other GHG accounting methodology changes needed. In D.10-12-035, the initial development of the GHG accounting methodology was primarily focused on natural gas-fired topping-cycle CHP facilities. Sierra Club CEJA, EPUC/CAC and CCC all contend that this inadvertently disincents both renewable-fueled and bottoming-cycle CHP from being procured. This is a problem since both reduce GHG against the double benchmark in far greater magnitude than traditional topping-cycle CHP. As pointed out by EPUC/CAC, a relatively simple change could be made to remove this negative incentive towards cleaner CHP units. EPUC/CAC advocates, for the purposes of GHG accounting only, that *all* renewable-fired and bottoming-cycle CHP facilities be thought of as "new." EPUC/CAC suggests this approach so that additional re-definitions need not be made.[67] While CCC advocates that any bottoming-cycle change should be separate and distinct, we agree with EPUC/CAC that this change should suffice to create an even playing field. While PG&E and SCE generically do not want QF/CHP Settlement Terms changed, neither specifies why EPUC/CAC's suggestion would create a negative market disruption or cause ratepayer harm. On balance, we agree with Sierra Club and CEJA, EPUC/CAC and CCC that a change is warranted for these two resource types. We therefore agree that it is reasonable for these facilities with large GHG emissions reductions potential to be treated as a GHG Credit and not as Neutral in order to ensure that they are given proper consideration during the GHG accounting methodology process.

7. Procedural Showings Demonstrating Inability to Meet Second Program Period Targets

In D.10-12-035, the Commission adopted several monitoring and reporting tools to track the three utilities' progress towards their MW Capacity and GHG Emissions Reductions Targets. The utilities can make a showing justifying the inability to meet a target because of price, GHG reduction potential, lack of offers, facility inefficiency, lack of need, and portfolio fit. The CHP Program contains a provision for a CHP Auditor to examine the competitive solicitation

[67] As appended to D.10-12-035, Section 7.3 of the QF/CHP Settlement Agreement extensively outlines the various methods of a CHP facility making a GHG Credit, Debit or being counted as Neutral. EPUC/CAC's suggestion is to treat bottoming-cycle and renewably-fired CHP as if it falls into the category of a Credit of a new facility per Term 7.3.1.1 and not as an existing facility per Term 7.3.3.1 where the facility is treated as Neutral.

choices if the utilities were to fail to meet a target or attempt to make such a showing.[68] The utilities also were placed under certain restrictions of what could not be used as justification in failure to meeting a target. In particular, the QF/CHP Settlement contains language[69] prohibiting the utilities from reasoning that a "lack of need or portfolio fit" justifies a failure to meet the 3,000 MW Capacity Target, but did extend that justification to the GHG Emissions Reduction Target.

D.10-12-035 did not establish an actual mechanism whereby the utilities can make such showings and the Commission can determine whether the showing is justified. The three utilities contend that no additional changes are needed beyond the established framework. ORA suggests that any showing made by the three utilities should occur via a motion in this (or presumably successor) proceeding or via a Tier 2 advice letter.[70] ORA states that either of these options would be procedurally sufficient as to not require a Commission decision and allow for prompt action. ORA also outlines the various provisions and places where there is existing guidance within the QF/CHP Settlement Agreement. TURN indicates that a change to the method for demonstrating a justification should be made only if there is full agreement amongst all the Settling Parties. EPUC/CAC indicates that insufficient bids should be the only rationale for the utilities to make such a showing. CCC indicates that additional intervention is required, but is not as restrictive as EPUC/CAC. CCC contends that since both SCE and SDG&E have fallen short of their MW Capacity Targets

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[68] *See* QF/CHP Settlement Term Sheet Section 9.1.2, as attached to D.10-12-035.

[69] *See* QF/CHP Settlement Term Sheet Sections 5.4 and 6.9, as attached to D.10-12-035.

[70] Opening Comments of ORA, at 11.

that they should have a higher threshold when it comes to a utility making a failure showing. CCC continues to suggest that there are pricing-related solutions, such as taking a second bid, which should be explored prior to a utility filing that it cannot meet its procurement obligations. Last, CCC argues that the CHP auditor as structured does not have enough power to be effective and that the lack of specific penalties for failure to meet targets undermines any benefit that such an audit may produce. AReM indicates that any utility failure to reach a target should not result in a new obligation for resources to be procured by ESPs. Sierra Club and CEJA indicate that if by the end of the Second Program Period the utilities have not met their obligations that the Commission create an "Extra Program Period" and set a date certain for the procurement to be concluded.

The Commission expects that the GHG procurement mandates we establish today will continue our objective of creating a CHP market in California. Given that we have decreased the GHG Emissions Reduction Targets for the Second Program Period and modified the accounting rules for existing efficient, renewable, and bottoming-cycle CHP facilities, the procurement targets are now at a reasonable and achievable level. Simply put, any such showing of failure to meet a target needs to be significant. The timeliness of the Commission's response to a utility's demonstration of, and justification for, a failure to meet the MW Capacity Target or GHG Emissions Reduction Target is critical to maintaining the regulatory certainty intended by the CHP Program.

We adopt ORA's suggestion to use the Advice Letter process. We favor the use of an Advice Letter instead of a motion for handling implementation related issues. However, we favor a Tier 3 Advice Letter over ORA's recommendation for a Tier 2 Advice Letter for the purpose of effectuating a justification pending Commission approval. Therefore, if a utility is unable to fulfill the obligations set forth in this decision, it is reasonable for the utility to file a Tier 3 served to this proceeding (or in a successor LTPP docket).

The utilities are directed to file redacted and confidential versions of the Advice Letter in order to protect market sensitive data (such as Offerors, bids, and evaluation methodology) that are necessary to demonstrate key indicators including the efficiency of the CHP facilities and associated GHG emissions reduction potential, offer prices, and need or portfolio fit.[71] In Energy Division's review of the Advice Letter, it may consider the conclusions of the CHP Auditor.[72] This procedural vehicle, in combination with the provisions already adopted in D.10-12-035, including the CHP Semi-Annual Reports, will provide sufficient context for Energy Division to propose a resolution addressing the facts, published for party comment, and a Commission vote. We decline to take any additional action or place additional restrictions on the showing at this time.

8. Transition Period Extension Consideration

In D.10-12-035, the Commission approved a set of Transition PPAs existing CHP facilities that were selling to a utility under a Legacy PPA expiring before July 1, 2015. The purpose of these Transition PPAs, in part, was to give operational certainty to an existing facility as it transitioned away from a must-take obligation under PURPA and into a competitive solicitation. As described above, we refer to the term length of these Transition PPAs as the Transition Period. The Transition Period commenced with the QF/CHP

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[71] QF/CHP Settlement Term Sheet, Section 6.9 at 34 and Section 5.4.1, at 30.

[72] QF/CHP Settlement Term Sheet, Section 9.1.4.1 at 42.

Settlement Agreement effective date on November 23, 2011 and lasts until July 1, 2015. Some parties have requested that the term of these contracts be extended to coincide with the end of the Initial Program Period, which is November 23, 2015.[73] For reasons explained below, we deny this request. The term of the Transition Period will remain unchanged, ending on July 1, 2015.

EPUC/CAC and CCC are the primary advocates for the extension of the Transition Period. The overarching concern raised by both parties is that since the Initial Program Period ends after the Transition Period, existing facilities do not have sufficient certainty to prepare a bid for the upcoming RFOs and compete for the remaining MW in the Capacity Target or for the GHG emissions reductions. EPUC/CAC is primarily concerned with existing efficient facilities that have yet to secure a new PPA. EPUC/CAC encourages the Commission to extend the Transition Period until all of the 3,000 MW from the Capacity Target authorized for the Initial Program Period have been procured. CCC contends that existing efficient facilities need a "viable opportunity" to compete in the Second Program Period; either the facility will be selected and can immediately transition or, if it is unsuccessful, will need the extension to make commercial decisions for the thermal host. CCC suggests[74] that the Commission could order the facilities still on the Transition PPAs to either bid into the RFOs in the Second Program Period or declare that they will not be seeking a new contract. CCC claims that in 2015 the SRAC energy price paid to facilities under these PPAs switch to a market-basis and that the capacity prices authorized in

[73] As established in D.11-10-016.

[74] Opening Comments of CCC, at 12.

D.07-09-040 are below current market levels, so that ratepayer harm is relatively minimal.

On the other side, the three utilities, ORA, and TURN all are opposed to extending the Transition Period. The three utilities indicate[75] that any extension is beyond the scope of items considered under the QF/CHP Settlement. The three utilities also contend that an extension of the Transition Period would increase costs including non-bypassable charges and create excess costs for its customers. ORA does not argue about the cost of extending the Transition PPAs, but points out that the perceived time delay was foreseeable and predictable. As a result, ORA disagrees that an extension is appropriate. TURN is against changing the date unless all settling parties agree to the change, since it would constitute a change to the underlying QF/CHP Settlement Agreement.

We agree with EPUC/CAC and CCC that the Transition Period created a period of operational certainty for the first three competitive solicitations "A, B and C" during the Initial Program Period. While we agree that operational certainty for existing facilities is important, it is unreasonable to have an open-ended extension as suggested by EPUC/CAC. Similarly, we disagree with the pricing analysis put forth by CCC. We note that the GHG Emissions Reduction Targets adopted in this decision provide a continued and sustained market beyond the Initial Program Period. We also note that the remaining MW requirement from the Initial Program Period will continue until procured. As a result, we are confident that a combination of the competitive solicitations, near-term bilateral agreements, and arrangements to sell excess electricity into

[75] Opening Comments of PG&E, SCE and SDG&E, at 20.

the market are appropriate avenues for the limited number of facilities that remain on the Transition PPAs. Therefore, it is unreasonable to extend the Transition Period. Since we are not persuaded that an extension of the Transition Period is warranted, we do not take up the arguments put forward by the three utilities, ORA and TURN. The July 1, 2015 date ending the Transition Period shall remain in effect.[76]

9. Special Targets or Adjustments for CHP Resources that can Significantly Reduce GHG (Bottoming-Cycle or Renewably-Fueled CHP)

CHP is primarily fueled by the combustion of natural gas in a topping-cycle configuration. Given our goal to use CHP as a GHG emissions reduction strategy, we consider whether or not to create special targets, mandates or other rule changes to promote CHP technologies which use renewable fuels or in a bottoming-cycle configuration, since when designed properly, have far greater potential to reduce GHG emissions. In light of the GHG Emissions Reductions Targets adopted today, we consider whether or not we need to take additional steps to carry out our policy objective of reducing GHG emissions via CHP procurement. With the expectation to the GHG accounting methodology change for renewable and bottoming-cycle facilities above, we do not create any additional policy incentives for these types of technologies.

Sierra Club and CEJA strongly advocate the use of a set-aside for renewably-fueled CHP and for clean bottoming-cycle CHP. Sierra Club and

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[76] CCC filed a Petition for Modification of D.10-12-035 on December 16, 2014 seeking an extension of the Transition Period under the Commission's CHP program. This decision does not bind the Commission's consideration of the CCC petition.

CEJA advocate for a specific mechanism to develop renewably-fueled CHP, including a 1/3 set-aside of any target the Commission may create. Sierra Club and CEJA advocate for the Commission to be broadly inclusive with different renewable CHP fuel types, including solar, biomethane, renewable hydrogen and geothermal.[77] Sierra Club and CEJA point to the RPS as an illustrative example of how a hard target can spur innovation in emerging technologies. While Sierra Club and CEJA generally support bottoming-cycle CHP, they present concerns about working fluids which could potentially contain toxic elements. CCC supports the concept of a target or set-aside for bottoming-cycle and renewably-fueled CHP as long as "such targets are distinct from the targets for gas-fired, topping-cycle CHP facilities."[78] CCC tempers that support by stating that "arguably, a specific incentive is already in place and no more is needed."[79] EPUC/CAC limits its suggestion to a fix in bottoming-cycle GHG accounting rules, as discussed above. ORA generally does not support a regulatory set aside for these technologies, indicating that natural market forces should suffice to allow for the procurement of low-GHG emitting CHP facilities. The three utilities argue that the establishment of special set-asides is beyond the scope of the LTPP. PG&E, SCE and SDG&E point out that there are multiple contractual pathways for these low-GHG emitting technologies but do not speak to why they think there is a relatively low uptake from bottoming-cycle and renewably-fueled CHP. The utilities also argue that these types of CHP facilities

[77] Opening Comments of Sierra Club and CEJA, at 11.

[78] Opening Comments of CCC, at 13.

[79] *Ibid*.

are eligible for subsidy funding under the Electric Program Investment Charge.[80] TURN argues that "there is no evidence on the record that CHP facilities that provide greater GHG reduction benefits are not able to compete in the existing CHP program."[81]

A review of the CHP Semi-Annual Reports, specifically at the to-date procurement, indicates that the three utilities have only minimally contracted with renewably-fueled and bottoming-cycle CHP facilities, primarily due to the fact that existing renewable QFs were ineligible to count toward the MW Capacity Target. While we support the concepts put forth by Sierra Club and CEJA, we are not persuaded that a specific set-aside or target is needed. We agree with TURN that no party has put forward any explanation or specific example of why these low-emitting GHG CHP facilities cannot compete. The one exception is a GHG accounting methodology fix that we have made above. Beyond that, we agree with CCC and with TURN that no other form of intervention is needed at this time to see these technologies succeed. In order to get the most amount of GHG emissions reduction benefit for the ratepayer dollar spent, we foresee that the utilities will aggressively pursue contracts with these technologies as appropriate. As ORA points out, we have removed a regulatory barrier and the natural market forces should work. If the procurement trends in RFOs in the Second Program Period do not reflect a change, then we will have a basis to reconsider this decision. For now, we decline to create a separate target or mandate for bottoming-cycle or renewably-fired CHP facilities. As a result,

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[80] Opening Comments of PG&E, SCE and SDG&E, at 21.

[81] Reply Comments of Turn, at 11.

we need not consider the three utilities arguments about such a change being outside of the scope of the proceeding.

10. Other Matters Raised In Comments

While not specifically asked about in Comments, both AReM and MCE raise some issues specific to unbundled customers and CHP procurement. We briefly discuss those matters here.

The first matter raised by both AReM and MCE concern whether or not unbundled customers could procure CHP on their own behalf. Both parties request that they be made responsible for their own fair share of any targets in the Second Program Period. In considering the QF/CHP Settlement Agreement in D.10-12-035, the then-Settling Parties gave the Commission a choice: either the IOUs could procure CHP on behalf of the unbundled customers and allocate costs accordingly <u>or</u> the unbundled customers could procure and pay for their fair share. In D.10-12-035, the Commission elected to have the IOUs procure CHP resources on behalf of the unbundled customers and to allocate the costs as appropriate through the Cost Allocation Mechanism. The Commission reasoned that unbundled customers such as ESPs and Community Choice Aggregators (CCAs) would have very limited options to procure CHP. The Commission also reasoned that it would be administratively easier to have the IOUs procure CHP and to monitor their progress on behalf of the unbundled customers. However, D.10-12-035 states[82] "we remain open to consideration, in a future proceeding, of proposals whereby ESPs and CCAs may opt out of IOU procurement and

[82] *See* D.10-12-035, at 56.

procure CHP resources on their own behalf." AReM and MCE comment that they now elect to do their own CHP procurement.

Both AReM and MCE indicate that they have gained experience contracting resources to satisfy programmatic mandates, such as the RPS and the Resource Adequacy program. We agree with AReM and MCE that the LTPP proceeding is the proper forum to raise a request. However, AReM and MCE do not provide any substantive plan or approach of how they could procure CHP resources. They do not have proposals of how they could meet the different procurement option types offered by the three IOUs, such as the AB 1613 Feed-in-Tariff or the other PPAs. Other than speculating that they can procure CHP at a lower cost, they do not provide any evidence or examples of why the IOU procurement to date has been unfair or unreasonable for unbundled customers. We continue to remain open to considering transferring the procurement obligation to the unbundled customers in the future, but making such a change requires a substantive showing of evidence that IOU procurement is unfair or unreasonable for unbundled customers and provision of viable procurement plans. Until that time, we elect to keep the choice made in D.10-12-035 in place.

The IOUs will continue to procure CHP on behalf of the unbundled customers, including ESPs and CCAs. By extension, it is reasonable to maintain the status quo for the Cost Allocation Mechanism for the resources procured in the CHP Program as adopted in Section 13 in the Settlement Term Sheet.

11. Comments on the Proposed Decision

The proposed decision of Administrative Law Judge Gamson in this matter was mailed to the parties in accordance with Pub. Util. Code § 311, and comments were allowed pursuant to Rule 14.3 of the Commission's Rules of

Practice and Procedure. Comments were filed on ____, and reply comments were filed on ____ by ____.

12. Assignment of Proceeding

Michael Picker is the assigned Commissioner in this proceeding. David M. Gamson is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The QF/CHP Settlement adopted in D.10-12-035 resolved multiple long-standing contentious issues, but primarily established a CHP procurement program to preserve resource diversity, fuel efficiency, GHG emissions reductions and other benefits and contributions of CHP. The CHP procurement program was designed to promote new, lower GHG-emitting CHP facilities and encourage the repowering, operations changes through utility pre-scheduling, or retirement of existing, high GHG-emitting CHP facilities.

2. The CHP procurement program in D.10-12-035 included both an Initial Program Period (from the QF/CHP Settlement effective date of November 23, 2011 until November 23, 2015) and a Second Program Period (from November 24, 2015 until December 31, 2020). The QF/CHP Settlement also created a Transition Period, which lasts from November 23, 2011 until July 1, 2015.

3. In D.10-12-035, the Commission established two over-arching goals for the QF/CHP Program. The first goal was to transition CHP procurement from a federal-jurisdiction standard-offer pricing model to a procurement program under state-jurisdiction using a market-based approach for pricing. The second goal was to optimize the state's existing CHP fleet as a GHG emissions reduction strategy.

4. CHP is considered to be a preferred resource in the state's "loading order" and in statute.

5. Pub. Util. Code § 372(a) states "it is the policy of the state to encourage and support the development of [CHP] as an efficient, environmentally beneficial, competitive energy resources that will enhance the reliability of local generation supply, and promote local business growth."

6. D.10-12-035 established a combined total of CHP procurement in the Initial Program Period of 3,000 MW, and a second target of 6.7 MMT of GHG emissions reductions from CHP. D.10-12-035 adjusts this second target for retail sales of the investor-owned utilities, which translates into a proportionate allocation of approximately 4.8 MMT.

7. In R.08-06-024, the Commission adopted a standard offer contract for small, highly efficient and new CHP facilities. This program is known as the AB 1613 Feed-in-Tariff.

8. The CEC created a minimum efficiency rule for eligible CHP technologies of at least 62%.

9. In 2011, the Commission modified the SGIP to expand eligibility to technologies that reduce GHG emissions, including some CHP technologies. The SGIP uses the AB 1613 Feed-in-Tariff requirements.

10. D.10-12-035 defers implementation details concerning the targets for the Second Program Period to this proceeding, including whether or not to adjust the overall 2020 GHG Emissions Reduction Target or to translate that target into a specific MW procurement mandate.

11. The capacity procurement activity from the Initial Program Period's 3,000 MW Capacity Target achieved 2.09 MMT towards the 4.8 MMT GHG Emissions Reduction Target (equaling 43% of the target) established in D.10-12-035 as of July 2014.

12. Over the next several years, other preferred resources are likely to lead to emissions reductions more cost-effectively than CHP, on the whole.

13. The nature of the electric grid has changed since the QF/CHP Settlement in terms of the potential for over-generation reliability concerns.

14. CHP resources have a significant potential to contribute to the over-generation concern.

15. A significant portion of GHG emissions reductions in the 2008 CARB Scoping Plan are devoted to CHP.

16. A downward adjustment in the GHG Emissions Reduction Target from CHP will likely be cost-effectively "compensated for" by strong performance in other programs, such as energy efficiency and RPS procurement.

17. The June 2012 CEC Report referenced by ORA provides the most useful and specific information in the record for calculating future CHP emissions reductions, and is consistent with our policy objections.

18. The June 2012 CEC Report's Medium Case estimates that the total annual CO_2e emissions reduction potential for the utility service territories by 2020 is 2.72 MMT.

19. Much of the GHG benefits will come from the fleet of existing CHP facilities. Optimization of existing CHP facility operations can result in significant GHG emissions reductions.

20. D.10-12-035 authorized a variety of CHP procurement options including market-based CHP-only RFOs as the primary procurement strategy, as well as an "Optional As-Available" program, bilateral negotiations, the PURPA-must take obligation for facilities under 20 MW, the AB 1613 Feed-in-Tariff for highly efficient new CHP, incentives for behind-the-meter facilities reducing GHG funded by the SGIP, and conversions to Utility Pre-Scheduled Facilities. In most

cases, any method of CHP procurement or strategy counts towards the utilities' targets.

21. The existing GHG emissions reduction accounting methodology established in D.10-12-035 and the exclusion of coal-fired QFs from counting toward the MW Capacity Target are designed to achieve the goal of decreasing high-emitting, low-efficiency CHP.

22. The QF/CHP Settlement's construct for determining the IOUs' GHG Emissions Reduction Target and the GHG emission accounting methodology may have had the unintentional adverse consequence of discouraging the re-contracting of existing efficient CHP facilities, particularly those that do not change operations and therefore cannot provide GHG Credits.

23. All parties support, or are neutral about, continuing competitive solicitations for CHP procurement.

24. The Commission receives valuable programmatic and market information from holding competitive CHP solicitations on a regular and predictable schedule.

25. A large cohort of existing CHP facilities have contracts that expire in the near term.

26. Commission resolutions have considered how the contracting of CHP facilities affect the utilities' obligations to maintain safe electric service for the public pursuant to Pub. Util. Code § 451.

27. The utilities' procurement activities with CHP facilities in the Initial Program Period have generally established contract terms and conditions that require the CHP facility to be operated in accordance with Prudent Electrical Practices.

28. In D.10-12-035, the Commission adopted a "double benchmark" for counting GHG emissions reductions from CHP facilities to determine if the combined production of heat and electricity from a CHP facility is more or less efficient than producing the two products separately.

29. The double benchmark includes an 80% efficient boiler (heat) and a heat rate of 8,300 BTU/kWH (electricity), which are used in the 2008 CARB Scoping Plan for estimated GHG emissions reductions.

30. The double benchmark is an accounting construct, and is not an accurate report of actual GHG emissions produced from the CHP facility.

31. D.10-12-035 allowed for the Commission to update the double benchmark assumptions (the heat rate and the standard boiler) during the Second Program Period.

32. The initial development of the GHG accounting methodology was primarily focused on natural gas-fired topping-cycle CHP facilities, which disincents renewable-fueled and bottoming-cycle CHP facilities from being procured, although no party has put forward an explanation or specific example showing that renewable-fueled and bottoming-cycle CHP facilities cannot compete.

33. Renewable-fueled and bottoming-cycle CHP reduce GHG against the double benchmark in far greater magnitude than traditional topping-cycle CHP.

34. In D.10-12-035, the Commission adopted several monitoring and reporting tools to track PG&E, SCE, and SDG&E's progress towards the MW Capacity and GHG Emissions Reduction Targets.

35. The GHG Emissions Reduction Targets adopted in this decision and the MW Capacity Targets remaining from the Initial Program Period provide a continued and sustained market beyond the Initial Program Period, which is an

appropriate avenue for the limited number of facilities that remain on Transition PPAs.

36. D.10-12-035 required the IOUs to procure CHP on behalf of unbundled customers and allocate costs through the Cost Allocation Mechanism, but left open for future consideration the ability of the ESPs and CCAs to opt out of IOU procurement and procure CHP resources on their own behalf.

Conclusions of Law

1. The two guiding principles in D.10-12-035 (to transition CHP procurement from a federal-jurisdiction standard-offer pricing model to a procurement program under state-jurisdiction using a market-based approach for pricing, and to optimize the state's existing CHP fleet as a GHG emissions reduction strategy) continue to be reasonable.

2. A downward adjustment to the GHG Emissions Reduction Target is appropriate for the Second Program Period.

3. The Commission's CHP Semi-Annual Report dated July 7, 2014 should be officially noticed.

4. The Second Program Period target should be robust enough to achieve CHP policy objectives established in D.10-12-035 other than GHG emissions reductions, including considerations of cost and need.

5. The Medium Case of the June 2012 CEC Report is based on reasonable assumptions, and is consistent with balancing policies of stimulating additional CHP procurement, ensuring adequate cost control and providing opportunities for other beneficial resources. It is reasonable to utilize the Medium Case as a basis to establish the magnitude of the GHG Emissions Reduction Target for the Second Program Period.

6. AB 1613 Feed-in-Tariff issues are outside the scope of this proceeding.

7. Because PG&E has procured emissions reductions in excess of its service territory's potential identified in the CEC Study, PG&E should not be required to hold solicitations during the Second Program Period. The excess 0.12 MMT from PG&E's share of emissions reductions should not be applied to the remaining GHG Emissions Reduction Targets for the other two utilities.

8. It is not necessary to authorize procurement in terms of additional MW Capacity Targets at this time.

9. Any future uptake or participation from CHP facilities of the AB 1613 Feed-in-Tariff should continue to be an active procurement strategy and count towards the utilities' targets.

10. It is reasonable to maintain the existing multiple CHP procurement options established in D.10-12-035.

11. Because the GHG Emissions Reduction Target acts as a market signal for preserving existing efficient CHP facilities and associated extant emissions reductions, and replacing inefficient facilities with new efficient facilities, there is no need to adopt a specific MW Capacity Target set-aside for existing facilities.

12. In order to achieve policy goals for existing CHP facilities, this decision should clarify sections within the QF/CHP Term Sheet.

13. The emissions reductions associated with the continued operations of the fleet of existing CHP facilities should be recognized.

14. The utilities should hold up to four competitive CHP solicitations in the Second Program Period, with the first solicitation held no later than 90 days of the start of the Second Program Period to ensure as smooth a transition for existing facilities as possible, and continuing on a near-annual basis.

15. The utilities should complete a more holistic examination of safety risks associated with CHP procurement.

16. It is not reasonable to assume that a more stringent double benchmark will result in fewer GHG emissions because the double benchmark is not an accurate representation of GHG emissions.

17. The double benchmark should remain unchanged in order to use it as a metric to measure progress in reduction of GHG emissions since adoption of the 2008 CARB Scoping Plan.

18. Considering all renewable-fueled and bottoming-cycle CHP facilities as "new" facilities, for GHG accounting purposes only, will create an even playing field with topping-cycle CHP facilities, and should not result in negative market disruption or ratepayer harm. No other intervention is needed at this time for these technologies to succeed.

19. Given the decreased GHG Emissions Reduction Targets and modified accounting rules for existing efficient, renewable, and bottoming-cycle CHP facilities, the procurement targets are reasonable and any utility showing that justifies failure to meet a MW Capacity Target or GHG Emissions Reduction Target should be significant and timely.

20. An Advice Letter is a reasonable method for demonstrating the inability to meet a MW Capacity Target or GHG Emissions Reduction Target.

21. A Tier 3 Advice Letter demonstrating inability to meet a MW Capacity Target or GHG Emissions Reduction Target is more appropriate than a Tier 2 Advice Letter because it will effectuate a justification pending Commission approval.

22. The Transition Period should not be extended, as a combination of competitive solicitations, near-term bilateral agreements, and arrangements to sell excess electricity into the market are appropriate avenues for the limited number of facilities remaining on Transition PPAs.

23. Transferring procurement obligation of unbundled customers from the utilities to the ESPs and CCAs remains a possibility, but shall require a substantive showing of evidence that IOU procurement is unfair or unreasonable for unbundled customers and provision of viable procurement plans. Such showing has not yet been made.

O R D E R

IT IS ORDERED that:

1. The revised greenhouse gas (GHG) Emissions Reduction Target and remaining need for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall be as follows:

(Million Metric Tonnes, MMT)	**PG&E**	**SCE**	**SDG&E**	**Total**
Revised Second Program Period GHG Emissions Reduction Target	1.22	1.22	0.28	2.72
Utility Progress Towards Goal as of 7/7/14	1.34	0.74	0.01	2.09
Remaining GHG Credits Needed (adjusted)	0*	0.48	0.27	0.75

2. Pacific Gas and Electric Company is not required to hold solicitations during the Second Program Period.

3. The existing combined heat and power procurement options established in Decision 10-12-035 shall continue.

4. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall account for emissions from efficient existing Combined Heat and Power (CHP) facilities with no change in operations

as a greenhouse gas Credit calculated against the previous two calendar years of data compared to the double benchmark. This accounting methodology change shall apply to CHP procurement in the Second Program Period Combined Heat and Power Request for Offers.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must attain the greenhouse gas Emissions Reduction Target for the Second Program Period by the end of the Second Program Period, December 31, 2020.

6. San Diego Gas & Electric Company and Southern California Edison Company shall hold up to four competitive Combined Heat and Power Request for Offers in the Second Program Period until the greenhouse Emissions Reduction Target is achieved, with the first solicitation held no later than 90 days of the start of the Second Program Period.

7. San Diego Gas & Electric Company's Megawatts (MW) Capacity Target of 51 MW shall be procured concurrently with the Combined Heat and Power Request For Offers in the Second Program Period, but no later than 2018.

8. Any increase in Pacific Gas and Electric Company, San Diego Gas & Electric Company, or Southern California Edison Company's greenhouse gas emissions obligations shall automatically flow through to the next available solicitation.

9. During solicitations held pursuant to the attainment of the greenhouse gas Emissions Reduction Targets in the Second Program Period, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall assess all Combined Heat and Power (CHP) offers upon their effects on public and environmental health and safety. This safety assessment should include an evaluation of the CHP facilities in terms of existing

applicable state or federal standards and programs in order to validate the likelihood of the counterparty operating the facilities in compliance with Prudent Electrical Practices.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue to use the double benchmark values of an 80% efficient boiler and 8,300 British Thermal Units per kilowatt hour.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall consider all renewable-fueled and bottoming-cycle Combined Heat and Power facilities "new" and treated as a "GHG Credit" instead of "Neutral," for accounting purposes only.

12. If unable to meet the megawatt Capacity Target or greenhouse gas Emissions Reduction Target established in Decision 10-13-035 and modified in this order, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall filed a Tier 3 Advice Letter and serve it on the service list to this proceeding or its successor. Redacted and confidential versions of the Advice Letter shall be filed, in order to protect market sensitive data necessary to demonstrate key indicators justifying the target failure.

13. The Transition Period for Combined Heat and Power facilities selling under a legacy power purchase agreement shall end on July 1, 2015.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall continue to procure Combined Heat and Power on behalf of unbundled customers and allocate costs through the Cost Allocation Mechanism.

15. The Commission's July 7, 2014 Combined Heat and Power Semi-Annual Report is officially noticed.

16. This proceeding remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California.